COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

VIRGINIA ELECTRIC AND POWER COMPANY

In re: Virginia Electric and Power Company's
Integrated Resource Plan filing pursuant to
Va. Code § 56-597 *et seq.*

Volume I

Case No. PUR-2017-00051

August 25, 2017

TABLE OF CONTENTS

PART A

Direct Testimony Summary - David R. Eichenlaub

My testimony addresses Virginia Electric and Power Company's ("DEV" or "Company") forecast of load, fuel prices, emissions prices, market prices, and implications of the Commonwealth's energy efficiency goal within DEV's 2017 Integrated Resource Plan ("IRP") and offers the following observations.

I believe that the models and methodologies employed by the Company to build its forecasting models and prepare forecasts generally conform to current model-building practices, have not revealed any significant deficiency in methodology and are generally sound and appropriate.

DEV's load forecast does not appear unreasonable. Although lower than the forecast of the 2016 IRP, DEV's load forecast still tends to reflect an upper range. The Company developed its forecast using base data from Moody's Economy.com of October 2016.

DEV's forecast of fuel prices appear reasonable and consistent with other external forecasts and current prevailing prices monitored by Staff. The fuel and energy prices forecast uses forward market prices as of September 29, 2016 and ICF's long-term estimates, also determined in the fall 2016. The use of portfolio risk analyses around fuel prices indicates the Company's 2017 Plans are robust with respect to a range of future possible price outcomes.

DEV's projected energy market prices and capacity prices for the regional transmission organization appear in line with current prevailing market prices and auctions.

DEV's forecast of emissions allowance prices for SO_2[1] appears reasonable compared to currently available market reports and regulatory activities. It is premature to have confidence in the expected higher long-term prices for NO_x[2] allowances since the recent Cross State Air Pollution Rule revision just went into effect.

DEV's projected prices for renewable energy credits ("RECs"), particularly solar RECs, appear to be quite inflated for years beyond the planning period, thus heavily influencing the addition of solar installations in the Company's 2017 IRP.

DEV's use of projected costs of CO_2[3] as a proxy for the effect of future carbon regulations on the operation of generation units is a possible method to examine state compliance with environmental requirements, particularly in light of the current uncertainty of such requirements.

The Commonwealth's energy reduction target for DEV's system is 6,179 gigawatt hours ("GWh") by 2020. DEV states that its 2017 IRP includes demand-side management programs that are expected to reduce its overall energy consumption by about 1,221 GWh by 2032. The IRP plans achieve 19.8% of the target level, while taking 12 years longer than requested by the Governor.

I encourage the Company to continue to enhance its understanding of the PLEXOS® model and refine its specific assumptions and sensitivity adjustments of its modeling data in future IRP filings, particularly regarding its forecast of peak and energy requirements, NOx allowance prices and REC prices.

---

[1] Sulfur dioxide.
[2] Nitrogen oxide.
[3] Carbon dioxide.

PRE-FILED TESTIMONY
OF
DAVID R. EICHENLAUB

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2017-00051

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is David R. Eichenlaub. I am a Deputy Director in the Commission's Division of Public Utility Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. On May 1, 2017, Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("DEV" or the "Company") filed an Integrated Resource Plan ("IRP") with the Commission ("2017 IRP").

The 2015 Session of the Virginia General Assembly enacted legislation that, *inter alia*, amended Code § 56-599, effective on July 1, 2015 ("2015 Amendments").[4] The 2015 Amendments, among other things, now require each investor-owned electric utility to file an IRP annually by May 1. The 2015 Amendments also require that IRPs evaluate the effect of current and pending environmental regulations upon the continued operation of the existing electric generation facilities or options for construction of new electric generation facilities and the most cost-effective means of complying with current and pending environmental regulations. Additionally, the 2015 Amendments require that IRPs address options for maintaining and enhancing

[4] 2015 Va. Acts Ch. 6.

rate stability, energy independence, and economic development, including retention and expansion of energy-intensive industries, and service reliability.

The purpose of my testimony is to evaluate DEV's IRP with regard to the Company's forecast of load; and fuel, emissions, and market prices (together referred to as commodity prices); and implications of the Commonwealth's energy efficiency goal.[5]

Q3. WHAT ARE THE GENERAL IMPLICATIONS OF AN IRP?

A3. An IRP is a planning tool with long-range assumptions determined at a particular point in time. Staff recognizes that resource planning is a dynamic and ongoing process and expects changes with each annual snapshot. As variables and regulations change, the IRP should adjust to adapt to such changes as the utility moves forward to reliably serve its customers and achieve various goals.

It is Staff's view that each IRP should be reviewed with an awareness that a utility must respond to constantly changing conditions, and, as such, an IRP is transitional in nature and does not necessarily represent absolute decisions. Although an IRP reflects a snapshot of assumptions, it must weigh risks and uncertainties relative to the numerous variables it considers. The use of scenario and risk analyses to evaluate the sensitivity of such variables around different possible future conditions helps to identify the robustness of the plan that should best meet the Company's expected needs while responding to external forces and policy goals.

Thus, an IRP addresses changes in significant variables affecting future load and energy requirements and the alternatives to supply such requirements. When

[5] 2007 Va. Acts Chs. 888 and 933, Third Enactment Clause.

making a business decision to pursue a particular resource option, the utility may, and often must, seek approval of the Commission prior to implementing the option. Upon such an application, the utility's proposal will undergo detailed scrutiny. An application for approval of a particular option (or to make a significant financial commitment therefor) may also include an application specifically addressing the issue of cost recovery for the proposed solution.

Q4. WHAT IS YOUR GENERAL ASSESSMENT OF THE COMPANY'S FORECASTING METHODOLOGIES?

A4. The Company's modeling tools and processes used to forecast energy sales, electricity demand, and commodity prices have evolved over a number of years. The Staff continues to review them in various Commission proceedings and finds generally that these models and procedures conform to current model-building practices, and have not revealed any significant deficiency in methodology.

The Company uses forecasts of the U.S. economy prepared by reputable sources to provide the macroeconomic drivers required to solve its in-house forecasting models. Likewise, the Company employs reputable sources of economic data for the coal, oil and natural gas industries and the power market to provide inputs for its forecasts of commodities. Thus, Staff believes that the methodologies employed by the Company to build its forecasting models and prepare forecasts are generally sound and appropriate.

The Company's forecasts and assumptions determine the input values to the PLEXOS® computer model[6] to simulate the operation of an electric utility power system. PLEXOS® is becoming more widely used as reputable computer software developed and supported by Energy Exemplar, LLC. In addition to the forecasts of electricity demand, kilowatt-hour sales, and commodity prices previously described, PLEXOS® requires additional input data on generating unit design parameters and operating factors, power market transactions, general system parameters such as reserve margins and reliability levels, and other economic and financial information to utilize its suite of mathematical optimization methods to help develop an IRP. The PLEXOS® model uses input fuel price projections along with other variable operation and maintenance costs and estimates of costs for emission allowances to simulate unit dispatch costs. Staff does not oppose the Company's use of PLEXOS® as a reasonable proxy of future system operations.

As Staff continues to gain experience through review of utility proposals based on the PLEXOS® model, Staff believes the model is well-designed and offers flexibility and advantages to the increasing focus on environmental factors and risk analysis. Staff will continue to work with the Company to gain a deeper understanding and become more comfortable with DEV's application of the PLEXOS® model and its results as a reasonable expectation of future system operations, given the reasonableness of the model's input assumptions.

Additionally, review of snapshots from prior IRPs assists the comparison of assumption trends and the development of future scenarios to consider in upcoming

[6] DEV elected to replace its prior long-term planning model, Strategist®, with a newer energy integrated planning model known as PLEXOS® effective with its 2017 IRP. As did Appalachian Power Company when it switched to PLEXOS® in 2014, DEV also ran Strategist® in parallel with PLEXOS® to learn and build confidence in the model and associated results.

IRP filings. Such analyses should consider a wide array of economic drivers to determine a reasonable long-term forecast of load, fuel prices, emissions prices, market prices, and environmental costs.

The only thing known for sure about any forecast is that it will likely not match what actually occurs given the uncertainties associated with a myriad of factors interacting in a dynamic system. There are several modeling tools and approaches that could be used in developing an IRP. None of the models or approaches is perfect and each has its own set of potential issues. That being said, regardless of the model or the approach, particular attention must be given to the input assumptions and whether those assumptions reasonably reflect future variable conditions.

Q5. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S LOAD FORECAST?

A5. A general review of the Company's previous IRP filings shows that DEV's forecasts of peak demand and energy tend to be higher than those actually realized. However, recognizing historic experience and trends, DEV's forecasts of peak demand and energy have generally declined with each IRP submitted to the Commission since 2009. Using data provided on Appendix 2H of each respective IRP for the following table, one can compare the base year projection of peak demand with the actual load realized for that base year, after adjustment for demand-side management ("DSM") programs.[7] Upon observation, one may conclude that the projected summer peak demand tends to be overstated more often than it is understated, compared to the peak demand actually realized for the base years shown below. Of course, these projected

[7] DSM programs are included in DEV's forecast reflecting such programs approved by the Commission and future programs for which the Company intends to seek Commission approval. The Commission holds distinct proceedings regarding the proposed DSM programs, upon submission of specific applications from DEV.

numbers are based on expected normal weather and actual weather plays a significant role in such a comparison. Other possible reasons for realized peak demands being less than expected could reflect energy efficiency efforts on the part of the consumer, aside from those of utility programs, that are not completely captured or that new housing or business startups are less than expected.

LSE Summer Peak	2009 IRP	2011 IRP	2013 IRP	2015 IRP	2016 IRP	2017 IRP
Base Year Forecast (MW[8])	16704	17032	17383	17442	17147	17319
Base Year Actual (MW)	16067	17661	16469	16530	16819	16634*
Year Forecast (MW)						
2016	19332	18238	18589	17926	17147	n/a
2017	19703	18546	18131	18302	17207	17319
2018	19970	18878	18314	18601	17578	17615
2019	20371	19197	18535	18779	17835	17928
2023	22137	20726	19678	19775	19724	18871
2024	22428	21007	19969	20186	20132	19225
15 Year CAGR[9]	2.0	1.6	1.3	1.5	1.6	1.4

*Approximate value for July 2017 based on PJM-South Zone Peak.

As seen in the sample of forecast data above, the Company's projection of adjusted peak demand for the load serving entity ("LSE") generally grows year-to-year as expected and as seen in the sample years illustrated within each IRP, but the rate of

[8] Megawatts.
[9] Compound annual growth rate.

growth has not slowed as much as one might expect reflecting recent and current economic conditions. It appears the Company does generally lower its expected base year forecast with each IRP, but then maintains a somewhat optimistic slope for its long-term forecast as seen by the estimated CAGR. One could surmise that recent slower than expected growth in the state and region economies may not be adequately considered in developing the Company's long-term forecasts.

Although PJM Interconnection, L.L.C.'s ("PJM") demand values generally tended to be somewhat higher than those projected by the Company a few years ago, PJM implemented enhancements to its forecasting methodology with the 2016 PJM Load Forecast Report issued in January 2016. The most important enhancements were to better capture past regional trends and forward-looking forecasts of equipment and appliance efficiency and saturation, as well as improving the relationship between weather and loads during periods of high loads due to extreme weather.

PJM's 2017 forecast reflects a continued downward load growth forecast for the Dominion Zone[10] with a 15-year CAGR of 0.4%, significantly lower than DEV's estimate of 1.4% for the LSE. Based on PJM's Annual Load Forecast Reports, PJM projected 15-year CAGR for the Dominion Zone of 1.6% in 2014; 1.5% in 2015; 1.1% in 2016 and 0.4% in 2017. Although, PJM's year-to-year decline is not unexpected, the sudden significant drop in 2017 is surprising. DEV points out on page 21 of its IRP that the actual Dominion Zone summer peak growth rate for the period 2002-2016 has averaged 1.2% annually, which is lower than DEV's 2017 forecast, but not as low as PJM estimates.

[10] PJM's Dominion Zone includes DEV's retail load in Virginia and North Carolina in addition to the loads of cooperative and municipal utilities interconnected to Dominion's transmission grid.

DEV identifies four key differences between its 2017 forecast and PJM's forecast on pages 25-29 of its IRP. DEV suggests that the way PJM handles the forecast of growth for data centers, solar PV distributed energy resources, appliance saturation and efficiency gains, and sales to local, state and federal governments, comprise most of the gap between DEV's forecast and PJM's forecast. Although still believed to be a significant contributor to load growth in the PJM region, PJM doesn't project growth in the Dominion Zone to be significantly above that of other LSEs in the PJM region, despite the interest in data centers in northern Virginia. Staff understands that significant strides have been made within the past few years regarding energy efficiency within data centers due to improvements to such items as spacing, air conditioning, equipment, and cable connections. However, it is not clear how PJM's or DEV's forecast considers such efficiency gains within the data center industry.

Although the Company's forecast may be higher than others might project, DEV's load forecast is not unreasonable or outside acceptable bounds. As seen in the table above, the Company's projected LSE peak demand is commonly higher than its actual LSE peak demand. Although perhaps in the upper range, the Company's projected demand is within an acceptable range of its actual demand.

Q6. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE FORECASTED FUEL PRICES?

A6. Fuel prices are forecasted by the Company using a comprehensive forecasting procedure that has been developed over a period of years and reviewed by Staff on numerous occasions. DEV developed its 2017 IRP using energy and commodity price forecasts provided by ICF International, Inc. ("ICF"), a recognized global energy consulting firm. The Company used forward market prices for the first 18 months of the study period and blended forward prices along with ICF forecasted prices for the next 18 months, and then relied on the ICF forecast estimates for the study period beyond 36 months. Additionally, for the short-term, the Company used a consistent procedure to estimate total fuel costs considering fuel inventories, contractual obligations, and spot market purchases. This forecasting procedure combines data on existing fossil fuel contracts, current spot market conditions, and current transportation costs to produce projected monthly estimates of coal, oil, natural gas, and nuclear fuel prices. Generally, the Company's forecasts of the various commodity prices appear somewhat lower than the forecasts included in the Company's 2015 and 2016 IRP. The Company's forecasts also appear to be consistent with recent conditions in the commodity markets.

DEV developed two different price scenarios for the 2017 IRP. DEV utilized a "No CO_2[11] Cost" scenario to evaluate the No CO_2 Limit alternative, referred to as Plan A. The No CO_2 Limit case assumes no new CO_2 laws or regulations, and does not satisfy the Clean Power Plan ("CPP"), a rule promulgated by the Environmental Protection Agency ("EPA") regarding CO_2 emissions from existing (and potentially new) generating units. On February 9, 2016, the United States Supreme Court granted a stay of the CPP pending judicial review. DEV asserts that Plan A reflects a commodity price forecast without the influence of CO_2 prices that may provide an alternative case to help evaluate the expected cost of compliance with the CPP. Further, Plan A could be a potential viable alternative to continue studying, pending the outcome of court actions and future decisions made by the federal administration.

[11] Carbon dioxide.

The "CPP Commodity Forecast" reflects CO_2 regulation of certain existing generation facilities based on limits specific to Virginia as proposed in the CPP. This price scenario was used to develop all of the CPP-Compliant Alternative Plans (identified as Plans B, C, D, E, F, G and H) to enable the Company to evaluate such plans using a commodity price forecast that reflects the proposed CPP.

The following observations and comments are based on price projections of the CPP Commodity Forecast.

The base price assumptions for the 2017 IRP reflect a downward turn in all fuel, energy and capacity prices from those estimated in the 2016 IRP. The projected Dominion Zone natural gas prices reflect continued decrease in cost and increase in gas production from shale formations. Considering expected increased demand for natural gas to fuel electric generating stations and industrial processes and uncertainties regarding pipeline capacity, DEV's current projected price to purchase natural gas during the planning period appears reasonable. Observation of Henry Hub Natural Gas Future prices indicates that today's relatively low gas-price environment is likely to continue and be sustained for several more years.

The nuclear fuel price model takes into account the price of uranium in world markets, transformation and enrichment costs, and fuel fabrication. Additionally, nuclear fuel prices include the added costs of decontaminating and decommissioning the U.S. Department of Energy's uranium enrichment facilities, as specified in Title XI of the Energy Policy Act of 1992. The Company's 2017 forecast of nuclear prices remained slightly below and relatively flat compared to the forecast used in its 2016 IRP.

DEV's forecasted prices for existing coal contracts are obtained by escalating current coal prices, based on predetermined conditions that are provided in the Company's fuel contracts. Non-contract coal prices are forecasted based on data from ICF using its models, CoalDOM® and IPM®, to integrate its comprehensive database of U.S. coal mine data, which is calibrated to recent government sources and company financial reports with data regarding international coal markets, transportation modes, and environmental regulations and controls.

The base coal price assumptions for the 2017 IRP reflect a decline of nearly 10% compared to those estimated in the 2016 IRP, primarily resulting from the declining local and global demand. Specifically, the reduction in electricity demand, competing lower natural gas prices, and environmental regulations have caused many of the older less efficient coal-fired plants to be idled, retired, or converted to a different fuel source. Coupled with the expectation of additional costs imposed on coal-fired plants for carbon emissions in the future, many utilities are evaluating the value of the aging coal fleet under dynamic circumstances.

The base oil price assumptions for the 2017 IRP reflect a decline compared to those estimated in the 2016 IRP. DEV's forecast of oil prices does not appear unreasonable given the volatility in oil prices observed over the past few years. The Company has no long term contracts to purchase oil or natural gas and both fuels are purchased on the spot market on an "as-needed" basis. Crude and fuel oil prices are forecasted by ICF reflecting its analysis of the oil market and considering the market price for oil futures at the New York Mercantile Exchange. DEV has indicated that it is exploring other procurement strategies for natural gas, particularly as it anticipates natural gas to contribute increasingly more to its future overall fuel mix.

Different from prior IRPs, the Company did not perform sensitivity analyses around its fuel prices forecast but rather now uses a portfolio risk analysis as discussed further in Staff Witness White's testimony. The Company states that this approach attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk that is not addressed in the traditional least-cost sense. Among the areas of portfolio risk identified and analyzed are coal and natural gas prices, CO_2 emission allowance prices, and electricity demand.

Staff understands that the Company now relies on its risk analysis process in lieu of the various sensitivity analyses included in prior IRPs. Staff does not object to this, however, Staff recommends that the Company provide relevant sensitivity analyses that may be requested by Staff through discovery in future IRPs. Staff notes that the Company has complied and provided such sensitivity model runs through discovery in the current proceeding.

Although the Company asserts that prices used in Plan A provide a comparative alternative to approximate the cost of compliance to the CPP, it could be argued that by simultaneously changing all prices in the Plan A scenario, the comparison to other plans cannot distinguish the difference in results from the effects of the CPP alone or from the effects of just the changes in prices. Realizing that no new CO_2 mandates would affect all future commodity prices that DEV evaluated, perhaps, Plan A could have also been performed with the CPP Commodity Forecast prices to try to distinguish the effects of changing prices and those of the CPP.[12]

The Company's forecast of fuel prices in the 2017 IRP appear reasonable and consistent with other external forecasts and current prevailing prices monitored by

[12] Staff requested such a model run be performed, which was subsequently provided by the Company.

Staff. Although one may argue whether the forecast of fuel prices should be higher or lower, the portfolio risk analyses around fuel prices indicate the Company's 2017 Plans are robust with respect to a range of future possible price outcomes.

Q7. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE FORECASTED MARKET PRICES?

A7. DEV utilized its projected fuel prices in conjunction with forward price curves for emissions allowance prices, projected regional loads, and available regional generation, to project market prices for electricity. The continuing effects of a slowly rebounding business cycle, corresponding reductions in electricity demand, and lower natural gas prices, lead to a general decline in wholesale electric power costs. DEV's forecast of power market prices for the 2017 IRP reflects a continued decline of peak- and off-peak energy prices compared to those estimated in the 2015 and 2016 IRPs and appears in line with current prevailing energy prices. Consistent with the recent regional transmission organization capacity prices from PJM's Reliability Pricing Model auctions, the Company shows a small increase in its forecast of market capacity prices for 2017 and 2018, and then a modest decrease in 2019 and beyond, compared to its 2016 IRP.

Q8. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE FORECASTED EMMISSIONS ALLOWANCE PRICES?

A8. The EPA has proposed and finalized several new regulations addressing air, water and solid waste conditions that will likely affect certain units in DEV's current fleet and units of choice in the future. As the Company reacts to comply with these regulations, so will other generation owners and operators, affecting future unit operation and prices across the country. Though there are differences of opinion as to how expensive compliance with these regulations will be, there is agreement that costs will be incurred and that costs will be passed on to customers.

Similar to the above discussion regarding market prices, the assumptions regarding the added costs of compliance with environmental requirements concerning SO_2, CO_2 and NO_x also play a significant role in driving an IRP. The estimated cost of emissions allowances for these effluents influences the IRP through the modeled economic dispatch of the bulk power system and decisions regarding unit refurbishment, retirements and additions.

The EPA's SO_2 cap and trade program, established under Title IV of the 1990 Clean Air Act Amendments, requires major emission reductions of SO_2, and sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units in the contiguous United States. The program was phased in, with the final 2010 SO_2 cap set at 8.95 million tons, a level of about one-half of the emissions from the power sector in 1980. When preparing the 2017 IRP, DEV expected a slight decrease in SO_2 allowance prices compared to those of the 2016 IRP.

On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule ("CSAPR") for the 2008 ozone National Ambient Air Quality Standards by issuing the final CSAPR Update. The rule was designed to reduce air quality impacts of ozone pollution that crosses state lines and to help downwind areas meet and maintain the 2008 ozone air quality standard. Starting in May 2017, this rule was revised to further reduce summertime (May - September) NO_X emissions from power plants in 22 states in the eastern part of the country. According to the EPA, this revision will provide up to $880 million in benefits and reduce ground-level ozone exposure for millions of Americans. Surprisingly, the annual NOx emissions levels were not adjusted, just those for seasonal ozone levels.

At the time of preparing the 2017 IRP, the Company expected a significant increase of CSAPR ozone season NO_x allowance prices throughout the study period while simultaneously, a significant decrease in CSAPR annual NOx allowance prices, as compared to those of the 2016 IRP. This was due to the anticipated market reactions to comply with the revised CSAPR regulations. It is too early to tell how the market is reacting to the lower emissions requirements or how accurate DEV's forecast of emissions allowance prices may be because of continued lower electricity demand and lower fuel prices. Further experience will assist DEV to better determine next year's estimates.

Q9. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE FORECASTED ASSUMPTIONS REGARDING FUTURE CARBON RESTRICTIONS?

A9. DEV's 2017 IRP accounts for potential impacts of the CPP, which influence the Company's forecasts of fuel prices, emissions allowance prices and market prices as well as the cost and value of DSM programs. In short, the Company's assumptions regarding potential carbon controls have significant implications with respect to what is an optimal IRP. Given the current challenges and uncertainty surrounding carbon restrictions, the Company's assumptions in this IRP do not appear unreasonable.

The IRP further suggests that projected CO_2 costs will remain at zero until 2022, the first year of CPP compliance, and then slowly rise throughout the remaining study period. However, beginning in 2022 the initial projected costs for CO_2 are significantly lower than those used in the 2015 and 2016 IRPs. The Company's projected cost of CO_2 emissions does not appear unreasonable, particularly in light of the current uncertainty regarding environmental requirements and state compliance.

Q10. DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY'S PROJECTIONS OF RENEWABLE ENERGY CREDIT ("REC") PRICES?

A10. Yes. The forecast reasonably assumes a convergence of Tier I RECS and Solar RECs, as that appears to be occurring in the current REC marketplace. The current and expected installations of solar generation have produced an abundance of solar RECs, saturating the market and leading to greatly reduced market values for such solar RECs. Current trading of solar RECs is at or near the trading levels of Tier I RECs.

Upon review of the data provided with Appendix 4A of the 2017 IRP and the Company's Response to Staff Interrogatory No. 2-19, DEV's forecast of its 2016 IRP indicated a modest increase in REC prices throughout the planning period 2016-2031 and then declining values throughout the remainder of the study period, when compared to the 2015 IRP. The current forecast used in the 2017 IRP shows a fair decline of REC prices during the early years of the planning period (2017-2024 or so), with a smaller decrease during the remainder of the planning period. However, prices beyond the planning period, after 2032, reveal a significant and continued increase throughout the study period. Such prices represent a significant divergence of REC prices used in either the 2015 or 2016 IRP. Although the later years of the study period are not directly reported in the 2017 IRP, such prices play a significant role in the planning model's selection of future resources, which could influence the results of the current IRP planning period of 2017-2032. A copy of the Company's response to Staff Interrogatory No. 2-19 is reproduced and attached as Schedule DRE- 1.

Subsequently, Staff asked DEV for any explanation regarding the significant rise in REC prices after the planning period. The Company filed its response to Staff Interrogatory No. 11-82, which is reproduced and attached as Schedule DRE-2. In its response, DEV states that "forward REC prices can be considered as reflective of the residual value over and above capacity and energy prices required for the marginal renewable generating unit to earn return on and of investment requirements."

The Company further states, "Relative to the 2015 and 2016 Plan forecasts, the wholesale energy price projections in the 2017 Plan are lower. The lower energy price provides less revenue to wind and other eligible Tier 1 resources, and hence, the residual value required from REC resources is significantly higher than in the 2015 and 2016 Plan forecasts, resulting in higher projections for the Tier 1 REC prices."

In other words, a renewable resource recovers its investment and return on such investment by collecting capacity, energy and REC prices. If the market capacity and energy prices decline, the Company assumes that REC prices increase to make whole the recovery of costs of the resource.

Given the current REC market, the forecast of fuel prices, the fact that future market energy and capacity prices are expected to decline, and the expected number of solar installations to increase significantly, one would not expect the value of RECs, particularly solar RECs, to increase so dramatically and be sustained in a competitive REC market. At this point, Staff does not have much confidence in the current REC forecast. As further discussed in Staff Witness White's testimony, the current forecast of REC prices directly influences the significant amount of solar installations projected by DEV in its 2017 IRP.

Q11. WHAT IS YOUR EVALUATION OF THE COMPANY'S EFFORTS TO HELP MEET THE COMMONWEALTH'S 10% ENERGY REDUCTION GOAL?

A11. In 2007, the General Assembly enacted the Regulation Act that, in its Third Enactment Clause ("Third Enactment Clause"), declared, in part, as follows:[13]

> That it is in the public interest, and is consistent with the energy policy goals in § 67-102 of the Code of Virginia, to promote cost-effective conservation of energy through fair and effective demand side management, conservation, energy efficiency, and load management programs, including consumer education. These programs may include activities by electric utilities, public or private organizations, or both electric utilities and public or private organizations. The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006.

On November 16, 2007, the Staff filed a report[14] pursuant to the directives set forth in the Third Enactment Clause, which stated in part that the Staff believes that the 10 percent electricity consumption reduction goal is achievable by 2022; that a mix of programs merit exploration to achieve the defined electric energy consumption reduction goal; and that if conservation costs less than new electrical supply, it can be deployed without increasing electric rates for non-participant ratepayers.

Based on energy sales in 2006, the Commonwealth's energy reduction target for DEV's system was 6,179 GWh by 2022, although Governor McAuliffe accelerated the goal to be realized by 2020. DEV states that its 2017 IRP includes DSM programs that

[13] 2007 Va. Acts Chs. 888 and 933, Third Enactment Clause.
[14] The entire report is posted to the Commission's website at http://www.scc.virginia.gov/pue/conserve.aspx.

are expected to reduce its overall peak demand by 428 megawatts and overall energy consumption by about 1,221 GWh by 2032, achieving about 19.8% of the target level, albeit taking twelve years longer than requested by the Governor.

Q12. WHAT ARE YOUR CONCLUSIONS?

A12. The Staff generally believes that the basic assumptions associated with the Company's forecast of fuel prices, market prices, and most emissions allowance prices and credits utilized in the Company's 2017 IRP are reasonable. Staff appreciates the difficulty expressed by DEV to determine a preferred plan given the uncertainties surrounding the CPP. Given these uncertainties, Staff also recognizes that it is too early to determine the full impact of the CPP on the Commonwealth. Staff encourages the Company to continue to refine the specific assumptions and risk analyses of its modeling data in future IRP filings, particularly regarding its forecasts of peak and energy requirements, NOx allowance prices and REC prices.

Q13. DOES THIS CONCLUDE YOUR TESTIMONY?

A13. Yes.

	Tier 1 REC Prices (Nominal)		
	CPP Commodity Forecast		
	2017 IRP	**2016 IRP**	**2015 IRP**
2015			$ 16.00
2016		$ 16.00	$ 16.51
2017	$ 10.75	$ 16.56	$ 16.96
2018	$ 11.25	$ 16.99	$ 17.33
2019	$ 10.35	$ 18.69	$ 16.42
2020	$ 10.56	$ 20.29	$ 15.50
2021	$ 11.26	$ 22.00	$ 12.77
2022	$ 12.01	$ 21.66	$ 13.62
2023	$ 12.81	$ 21.33	$ 14.54
2024	$ 13.66	$ 21.00	$ 15.51
2025	$ 14.56	$ 20.67	$ 16.53
2026	$ 15.53	$ 22.05	$ 17.70
2027	$ 16.57	$ 23.53	$ 18.95
2028	$ 17.69	$ 25.12	$ 20.29
2029	$ 18.89	$ 26.81	$ 21.72
2030	$ 20.15	$ 28.61	$ 23.25
2031	$ 21.50	$ 26.25	$ 20.51
2032	$ 22.94	$ 20.71	$ 17.65
2033	$ 24.47	$ 16.35	$ 14.68
2034	$ 26.10	$ 12.90	$ 11.60
2035	$ 27.83	$ 10.18	$ 8.38
2036	$ 29.66	$ 8.03	$ 5.04
2037	$ 31.60	$ 7.37	$ 1.57
2038	$ 33.68	$ 6.68	$ 1.60
2039	$ 35.89	$ 5.96	$ 1.63
2040	$ 38.24	$ 5.21	$ 1.66
2041	$ 40.75	$ 4.42	$ 1.69
2042	$ 43.25	$ 3.60	$ 1.72

Company Response to Staff Interrogatory 2-19

Virginia Electric and Power Company
Case No. PUR-2017-00051
Virginia State Corporation Commission Staff
Eleventh Set

The following response to Question No. 82 of the Eleventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on August 15, 2017 has been prepared under my supervision.

Original signed by

Marie F. Scheller
Vice President and Director
ICF International

Question No. 82

Please refer to the table the Company provided in response to Staff Interrogatory 2-19 that compares expected REC prices for the 2015, 2016 and 2017 IRPs for the 15-year planning periods and beyond through 2042. Please provide an explanation for the sudden and significant incline of Tier 1 REC prices in the 2017 IRP for years beyond the planning period (after 2032) when compared to the 2015 and 2016 IRPs.

Response:

As with prior year forecasts (2015 and 2016 Plans), the 2017 Plan Tier 1 REC price forecast is the outcome of the detailed production cost and forward market simulation modeling analysis performed by ICF using its Integrated Planning Model (IPM®). The methodology utilized to generate Tier 1 REC prices is consistent with prior forecasts and relies on an integrated approach to capture the interaction of wholesale energy, capacity, and tradable REC markets. The methodology assumes competitive economic pricing results based on marginal cost recovery. Fundamentally, forward REC prices can be considered as reflective of the residual value over and above capacity and energy prices required for the marginal renewable generating unit to earn return on and of investment requirements.

Factors driving the resulting Tier 1 REC market prices include demand-side requirements – i.e., the level (equivalent MWh) of renewable energy required from Tier 1 resources - and supply-side requirements (the marginal payment necessary to make marginal resources whole after energy and capacity prices). While demand requirements assumed in the 2017 Plan are slightly below those assumed in the 2015 and 2016 Plans due to lower projected load growth, supply requirement assumptions vary more significantly. These factors reflect a large body of assumptions and resulting market prices; key elements impacting the Tier 1 REC prices are listed below:

- The assumed tax incentives available to eligible resources has changed. Prior Plan forecasts assumed that the Production Tax Credits ("PTC") were not available to wind resources, while the 2017 forecast assumes that the PTC is available at declining rates through 2022. This tends to have implications to the near-term, reducing the 2017 near term REC forecast relative to the forecast projections from prior Plan years. Assumptions beyond 2022 are consistent across forecast vintages.
- Relative to the 2015 and 2016 Plan forecasts, the wholesale energy price projections in the 2017 Plan are lower. The lower energy price provides less revenue to wind and other eligible Tier 1 resources, and hence, the residual value required from REC resources is significantly higher than in the 2015 and 2016 Plan forecasts, resulting in higher projections for the Tier 1 REC prices. That is, given the reduction in expected revenues to renewable supply from wholesale energy sales, the price at which renewable supply will be offered in the REC markets will increase to ensure adequate returns in the electric energy markets. Drivers of the change in energy price include changes to the carbon control policy requirements relative to the 2015 and 2016 Plans and the market impacts thereof, and reductions in commodity fuel prices, in part due to the C02 policy changes, but also driven by fuel supply and demand fundamentals.